Mt. Rundle, an original watercolor by Fanny Fynebuik, depicts the peaceful ruggedness of the famous Alberta landmark.

Ms. Fynebuik, a graduate of the Dutch College of Arts and Crafts, was born in Holland and has resided in Calgary since 1957. An active member of the Calgary Sketch Club and the Federation of Canadian Artists, she has also studied at the Alberta College of Art and is the recipient of several awards.

92-07445/

Alberta PETROLEUM MARKETING COMMISSION
1900 - 250 Sixth Avenue S.W, Calgary, Alberta, Canada T2P 3H7 Telephone (403) 297-5500 Fax (403) 263-8144

April 30, 1992

The Honorable Rick Orman
Minister of Energy
Government of Alberta
Legislature Building
Edmonton, Alberta
T5K 2B6

Dear Sir:

In accordance with the provisions of the Petroleum Marketing Act and the Take-or-pay Costs Sharing Act, the Alberta Petroleum Marketing Commission has prepared a general report summarizing its transactions and affairs for the fiscal year ended December 31, 1991. I have the pleasure to submit the 1991 Annual Report that you may lay a copy before the Legislative Assembly.

Respectfully,

Gordon R. Scott
Acting Chairman

MESSAGE FROM THE CHAIRMAN

World oil markets weathered major political disruptions during 1991. Prices briefly spiked prior to the commencement of the Gulf war, then quickly stabilized as supply concerns evaporated. By year end, prices had weakened in response to over-supply and lower demand.

Canadian crude oil marketers were challenged by capacity constraints on the Interprovincial Pipe Line system, which magnified problems with the nomination process. The APMC led a shipper-pipeline task force in developing solutions which will be implemented in 1992. Loss of the Montreal market through closure of IPL's Montreal Extension led to increased pressure on prices during the latter half of the year, particularly on heavy crudes. The APMC pursued non-traditional markets to avoid shut-in and help rebalance supply and demand.

Weak prices prevailed in North American natural gas markets, reflecting continued over-supply. However, exports continued to improve and gas began flowing into the United States Northeast on the Iroquois Gas Transmission system. Canadian producers faced serious threats to existing long-term supply contracts for the California market as a result of determinations by the California Public Utilities Commission. The APMC assisted in attempting to alleviate the resulting difficulties and coordinate the required commercial restructuring of the existing chain of contractual arrangements between producers and buyers. A major effort to reduce the threat to Alberta's largest export market from this regulatory impasse will continue to be a high priority.

During the year, the APMC was active in a wide variety of oil and gas regulatory proceedings in Canada and the United States involving pipeline facilities expansions, tolls and rate design, and pipeline service restructuring. The APMC's participation in these proceedings protects and enhances the value of Alberta's petroleum resources and helps ensure that regulatory determinations provide fair market access to Alberta producers. Responding to developments affecting crude oil pipeline market access and to the effect on Canadian gas markets of the implementation of the United States Federal Energy Review Commission's Mega-NOPR will be particularly prominent among the APMC's regulatory activities in the coming year.

The Commission recognizes the leadership and contribution of Dale Lucas, Chairman for the past seven years, a period of significant change and challenge.

Gordon R. Scott
Acting Chairman

MARKET OVERVIEW

PETROLEUM MARKETS

1991 was marked by significant political upheaval internationally, including the Gulf war, a failed Moscow coup and subsequent dissolution of the Soviet Union. Combined with dramatic changes elsewhere in Eastern Europe, the way has been paved for integration of the European energy sector. The European Energy Charter, signed in December 1991, and the European Economic Community's proposed carbon tax are first steps in this direction. While producer-consumer dialogue was enhanced by cooperative efforts during the Gulf war, the United States continued to refuse to discuss any form of market management.

World crude oil markets greeted this political turbulence with equanimity. Oil prices were relatively stable throughout most of the year, as the continued absence of Iraqi exports and uncertainty regarding Soviet affairs tended to offset sluggish oil demand and otherwise growing Organization of Petroleum Exporting Countries (OPEC) supplies. The defeat of Iraq removed a physical threat to Saudi oil production and export facilities and enhanced Saudi Arabia's position within OPEC. The market generally interpreted this as an assurance that oil supplies will continue to be adequate, despite relatively little spare productive capacity worldwide.

North American oil prices were also fairly stable throughout most of the year, fluctuating between US$20.00 and US$23.00 per barrel. There were two notable, albeit temporary, deviations from this range. The first was in early January, when prices rose past US$25.00 per barrel with the approach of the Gulf war. The second saw prices plunge below US$19.00 per barrel in mid-December as warm weather, continued recession, rising OPEC production and higher than anticipated Soviet exports combined to create an oil glut. For the full year, prices on the New York Mercantile Exchange (NYMEX) for West Texas Intermediate crude oil (WTI) averaged US$21.50 per barrel, down approximately US$3.00 per barrel from 1990.

The price for the OPEC basket of crudes also fell, averaging US$18.65 per barrel for the year. This was substantially below OPEC's target price of US$21.00 per barrel set at OPEC's July 1990 meeting. Despite significant production declines in war-torn Iraq and Kuwait, OPEC output rose fractionally during 1991, to 23.4 million barrels per day, the highest level since 1980. Saudi Arabia production increased significantly, from an average 6.3 million barrels per day in 1990 to 8.2 million barrels per day last year.

Non-OPEC crude oil output (including from the former centrally planned economies) fell by 500 thousand barrels per day during 1991, to 41.4 million barrels per day. This reflected the net effect of a 1.1 million barrels per day loss in Soviet output, combined with a 600 thousand barrels per day gain elsewhere, split evenly between members of the Organization of Economic Co-operation and Development (OECD) and the developing countries. As a result, total world oil production in 1991, including OPEC natural gas liquids, was 66.8 million barrels per day or 200 thousand barrels per day below 1990's level.

World oil consumption averaged 66.3 million barrels per day during the year, implying an inventory build of 500 thousand barrels per day. Demand for 1991 was a scant 200 thousand barrels per day greater than during the previous year, reflecting poor economic growth and relatively mild weather. On a regional basis, lower demand in North America coincided with higher demand in Europe and Japan. Within the non-OECD, the impact on oil demand of economic dislocation in the former centrally planned economies was slightly more than offset by growth in the developing countries.

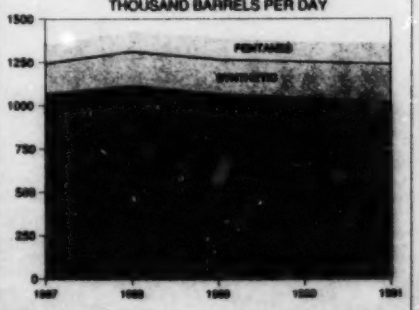
United States

During 1991, United States crude oil production essentially was flat, at 7.4 million barrels per day, stalling the strong downward trend evident since 1985. This halt in decline likely will be temporary as it reflected mainly nonrecurring factors, such as enhanced recovery programs in Alaska and additional drilling in response to crisis-induced oil price increases early in the year. Recent production and drilling data suggest that the long-term decline trend has now resumed.

Because of the ongoing recession and relatively warm weather, total United States petroleum deliveries continued to decline from 1990, to 16.6 million barrels per day. This second consecutive annual decline brought domestic oil consumption back to 1987 levels. Demand for all main petroleum products decreased, led by a five percent reduction in residual fuel oil demand. The decline in gasoline demand abated somewhat from previous years, averaging less than one percent below the 1990 level.

As a result of lower product consumption and steady domestic oil production, petroleum imports declined to 7.6 million barrels per day - a drop of five percent, or 407 thousand barrels per day. Product imports decreased the most, falling by 321 thousand barrels per day, to 1.8 million barrels per day. Crude oil imports declined marginally (1.5 percent) from their 1990 level of 5.8 million barrels per day. As a result, the United States' net dependency on imports was reduced by 1.5 percent, to 45.5 percent. Total stocks in the United States by year-end were one percent higher than 1990's level of 1,045 million barrels.

FIGURE 1
ALBERTA CRUDE OIL PRODUCTION
THOUSAND BARRELS PER DAY



Canada

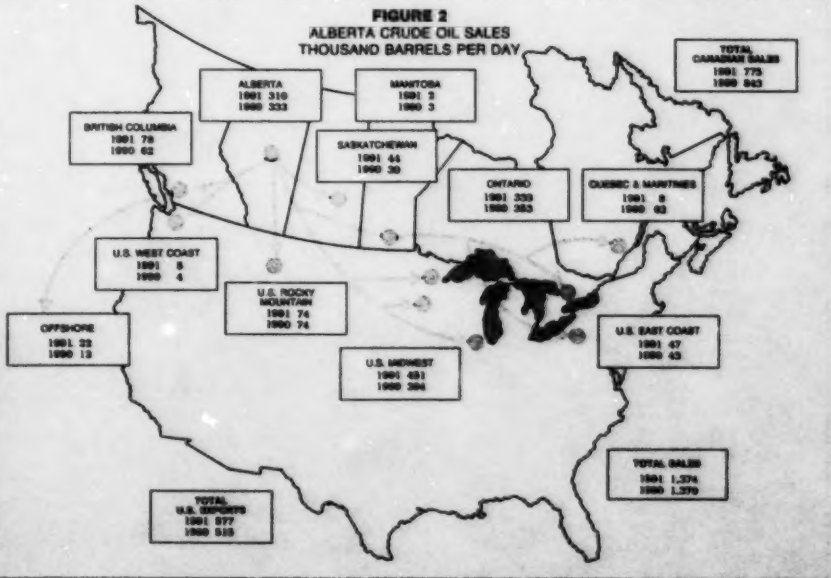
Canadian crude oil production averaged 1.65 million barrels per day during 1991, a one percent decrease from 1990. Higher oil prices during the Gulf crisis helped slow the rate of decline from previous years. Alberta production also fell slightly below the 1990 level (Figure 1).

Conventional and non-conventional output showed opposite trends. The former declined by two percent, while the latter rose by nine percent, mainly because of improved performance at the Syncrude plant.

Sales of Alberta crude oil in 1991 averaged 1.37 million barrels per day (Figure 2), unchanged from 1990. While Canadian deliveries dropped by 67 thousand barrels per day, due primarily to the closure of Interprovincial Pipe Line Inc.'s (IPL) Montreal Extension, exports to the United States and offshore increased by roughly the same amount. The bulk of additional export sales (73 thousand barrels per day) went to the United States Midwest, while offshore deliveries more than doubled, to 22 thousand barrels per day. Hydrostatic testing of IPL's Line 3 created high levels of apportionment and forced Alberta producers to seek alternative markets.

Domestic oil demand shrank by a significant six percent, to 1.46 million barrels per day in 1991, reflecting the depressed economy. Most affected by the recession and more stringent environmental controls were demands for heavy fuels and asphalt, declining by 14 and 10 percent respectively. Canadian refiners responded with significantly higher exports of gasoline and middle distillates and a five percent reduction in crude runs. Slower refining activity led to a 27 percent increase in crude oil stocks, to 22.1 million barrels at year-end.

FIGURE 2
ALBERTA CRUDE OIL SALES
THOUSAND BARRELS PER DAY



Overall, 1991 was a year of profound political change internationally which will have ongoing implications for world crude markets. Meanwhile, the Canadian oil industry continued to strive to reduce debt levels and restore profitability in the face of impaired cash flows. Heavy oil producers were particularly burdened by a combination of depressed demand and extremely low prices. The coming year is expected to bring continuing challenges to Canada's oil industry.

NATURAL GAS MARKETS

As a result of the continuing oversupply of natural gas in both Canada and the United States, gas prices continued to decline in 1991. Attention in the Alberta gas industry mainly focused on California, both with respect to new pipeline projects, and to the implications of changes in California regulatory policies regarding existing long-term supply arrangements. The APMC closely monitored changing market conditions in California, and analyzed the proposed Pacific Gas Transmission Company (PGT) expansion and Altamont Gas Transmission Company project.

Notwithstanding weak prices and uncertainty in the California market, there were some positive developments for the gas industry in 1991. Sales of Alberta gas rose by five percent because of growth in exports, particularly to the Northeast. The expansion of the TransCanada PipeLines Limited (TCPL) system and the completion of the Iroquois Gas Transmission System Pipeline project were major steps towards market diversification for Alberta gas producers.

In its analysis of natural gas markets, the APMC monitors:

- gas prices and sales volumes;
- major market developments; and
- pipeline transportation costs.

This information is collected on a confidential basis under Part 4 of the Natural Gas Marketing Act, as well as through market surveys and extensive industry contacts.

The information is used to assist in developing government policy and establishing the monthly average market price for determining the royalty share of gas production. The APMC's analysis of gas markets and prices also provides insight as to the competitive position of Alberta gas in domestic and export markets and enhances regulatory representation made by the APMC with respect to market access issues.

Canada

Total domestic end-use consumption of natural gas was 1.9 trillion cubic feet in 1991, only one percent higher than the previous year. Producers continued to face gas-on-gas competition in a weak market. While the effects of the recession on demand were more pronounced in central Canada than in the west, all domestic gas consuming areas experienced warmer-than-normal temperatures during the winter.

FIGURE 3
ALBERTA NATURAL GAS SALES
BILLION CUBIC FEET

Total domestic sales of Alberta natural gas fell by two percent to 1.7 trillion cubic feet (Figure 3). Aside from demand-related reasons, sales to Ontario fell because of competition from Saskatchewan-sourced supply. The proportion of Alberta gas sold to other provinces under long-term arrangements (Figure 4) decreased due to the loss of core market share. As a result of these factors, prices for interprovincial gas sales fell by five percent during 1991.

Market forces continued to shape interprovincial trade in natural gas over the year. Gas buyers pursued a portfolio of supply and transportation options, as witnessed by events such as an Ontario local distribution company (LDC) agreement to import United States-sourced gas, a Manitoba LDC agreement to access storage facilities in Michigan through backhaul transportation, the restructuring of its gas supply to a diverse portfolio of sellers by a British Columbia LDC, and preliminary discussions by market participants to convert IPL's Montreal Extension into a gas transmission system.

During the year confidence in gas supply deliverability also led the Manitoba Public Utilities Board to decide to allow the province's end-users, including the core market, to access direct sales arrangements. Security of supply and environmental concerns enhanced the potential for gas-fuelled cogeneration as an alternative in Ontario and Quebec for their long-term future electrical supply mix.

United States

Led by growth in the industrial sector, United States natural gas demand rose by three percent in 1991, to 19.3 trillion cubic feet. Industrial demand growth mainly reflected the increased use of gas for non-utility electrical generation and in fuel switching.

Natural gas spot prices averaged US$1.37 per thousand cubic feet, a decline of US$0.21 per thousand cubic feet (13 percent) from 1990 levels. While prices were down in 1991, there was a very sharp drop in the first quarter because of warm temperatures and high storage levels.

Natural gas futures trading on the NYMEX entered its second year in 1991 with increased volumes and greater volatility. A total of 422 thousand contracts were traded during the year, equivalent to approximately 20 percent of North American annual consumption. The spot market increasingly tracked the NYMEX throughout the year, as smaller producers became more active on the NYMEX. The APMC continued to monitor the NYMEX market and its impact on spot pricing.

During 1991, Canadian natural gas exports increased to 1.7 trillion cubic feet (17 percent), while Canada's share of United States consumption increased one percentage point to nine percent. The United States Northeast saw the strongest growth in imports, climbing about 70 percent, to 194 billion cubic feet. This, together with growth in the Midwest and Pacific Northwest, more than offset a decline in exports to California.

While Alberta's share of Canadian exports declined by two percentage points to 87 percent (1.5 trillion cubic feet), Alberta's volumes increased by 14 percent. Short-term sales dominated with growth of 51 percent (261 billion cubic feet) while long-term sales declined slightly (Figure 5). Average export prices fell by about five percent.

FIGURE 4
INTER-PROVINCIAL SALES OF ALBERTA NATURAL GAS

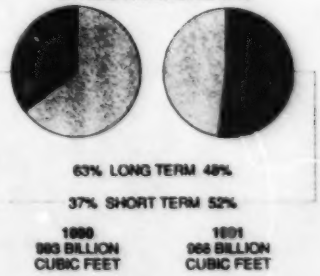


FIGURE 5
CANADIAN NATURAL GAS EXPORTS

Events in the export market focused on Northern California. The Alberta and Southern Gas Co. Ltd. (A&S)/Pacific Gas and Electric Company (PG&E) price renegotiation in mid-year required a record four ballots before finally being approved by producers, at a price US$0.31 per million Btu's below the previous year's contract.

A number of California Public Utilities Commission (CPUC) decisions during the year threatened existing long-term supply arrangements and prematurely terminated the Access Agreement which provided for direct sales of 250 million cubic feet per day to non-core California markets for a three-year term. The Alberta Department of Energy and the APMC engaged in negotiations with the CPUC at year end to attempt to defuse the mounting regulatory tensions.

During the latter half of the year, a facilitator was retained by the APMC on behalf of the A&S pool to coordinate a commercial restructuring of the existing set of contractual arrangements between PG&E, A&S and producers. This process was initiated and managed under a directive issued by the APMC pursuant to Section 9.1 of the Natural Gas Marketing Act. Restructuring negotiations continue into 1992.

During this turbulent period, the PGT expansion and Altamont project continued to vie for the right to transport incremental volumes of Canadian gas to the California market. At the request of Alberta's Minister of Energy, the Energy Resources Conservation Board established a public review process for the projects and will report its findings to the Minister during 1992.

Producer netbacks from California will continue under pressure during 1992 as an additional 1.1 billion cubic feet per day of gas supply comes onstream from the Rocky Mountain and San Juan regions through the new Kern River Gas Transmission Company and Mojave Pipeline Company pipelines, and the El Paso Natural Gas Company and Transwestern Pipeline Company expansions.

In the Northeast, the Iroquois pipeline began flowing Canadian gas in December 1991. Volumes will gradually increase during 1992 to 575 million cubic feet per day. This is a positive and timely development, given the currently depressed state of the industry, and the potential for market growth in the Northeast.

Overall, it appears that natural gas prices will remain weak over the near-term as the North American industry struggles with oversupply and the economic recession. In response, some producers, mainly in the United States, are reevaluating their shut-in policies and several states are considering production prorationing schemes. Meanwhile, Canadian exports, particularly to the Northeast, are likely to continue to increase as new pipeline capacity is phased in.

CRUDE OIL

OVERVIEW OF OPERATIONS

The APMC is responsible for gathering and marketing crude oil taken as royalty-in-kind from Crown leases in the Province. It also markets Alberta's 16.74% equity share of synthetic oil from the Syncrude Canada Ltd. project and offers contract marketing services to Alberta producers. Its objective in these activities is to maximize for the Province the benefit derived from the resource.

As the largest marketer of crude oil in Canada, the APMC maintains a high level of sales and transportation expertise to support its marketing activities. It manages a diversified sales portfolio, supplying crude to a wide base of refiners throughout Canada and the Northern United States. It also maintains a high profile within Alberta, gathering crude at more than one thousand receipt points throughout the province for feeder pipeline transport to local refineries or injection into extra-provincial pipeline systems. It participates in numerous formal and informal proceedings to promote an efficient operating environment, beneficial to the long term interests of the producing industry and the Province.

The magnitude and scope of APMC interests and activities cause it to play a prominent role in developing longer term sales opportunities which may require long lead times and which may not always represent immediate revenue maximization. The APMC draws from its direct involvement in the marketing and transportation of crude oil to keep the Government of Alberta advised of ongoing developments and market trends.

MARKETS

World response to the Iraqi occupation of Kuwait re-emphasized the strategic importance of Middle East crude oil to the world economy.

War fears pushed the price for West Texas Intermediate (WTI) January contracts to nearly US$29.00 per barrel. However, following the mid-February expulsion of the Iraqi army from Kuwait, oil prices returned to their pre-invasion levels, averaging about US$21.40 per barrel for the remaining three calendar quarters.

WTI prices firmed during the early months of the last quarter of the year, reflecting concern over the impact of the collapse of the Soviet Union on world supply. However, late in the fourth quarter, the combined effects of reduced demand due to the recession, a relatively warm winter, plus anticipated recovery of Kuwaiti production mitigated these concerns. Consequently, oil prices started to deteriorate as the year ended (Figure 6).

FIGURE 6
NYMEX 1991 WTI SPOT MONTH
AVERAGE SETTLEMENT PRICES
U.S. DOLLARS PER BARREL

SUPPLY

Kuwaiti oil production lost due to the Iraqi invasion was replaced primarily by increased production from Saudi Arabia and Venezuela. Replacement crudes were generally of poorer quality than those they replaced. In response to the relative oversupply of light sour and heavy crudes, prices for these types became depressed relative to sweet crudes.

PRICING

Table 1 lists the monthly reference prices for sweet and sour crudes paid by the APMC during 1991 which were approximately $2.60 per cubic metre ($0.41 per barrel) higher than Canadian refiners' postings. Since deregulation in June, 1985 APMC prices have averaged slightly higher than those posted by Canadian refiners.

TABLE 1
1991
CRUDE OIL REFERENCE PRICES
(DOLLARS PER CUBIC METRE)

	SWEET CRUDE	SOUR CRUDE
JAN	184.50	166.00
FEB	156.66	136.61
MAR	139.08	119.29
APR	141.26	122.73
MAY	146.26	130.18
JUN	140.66	131.10
JUL	145.74	141.35
AUG	148.20	143.71
SEP	146.42	139.63
OCT	154.19	144.14
NOV	153.71	139.85
DEC	137.82	115.41
AVG.	149.58	135.83

Prices shown are for crude oil with a density of 825 kilograms per cubic metre and a sulphur content of not more than 5 grams per kilogram delivered into, respectively, sweet or sour pipelines.

Figure 7 compares the average of Canadian refiners' par crude postings with WTI, transportation adjusted to Edmonton. The increased differential reflects high levels of capacity apportionment on Interprovincial Pipe Line Inc. (IPL) and declining domestic oil demand.

The integrity of Canadian postings as an indicator of market value was called into question during the latter months of 1991. By year-end, one poster had opted for a non-traditional quality adjustment mechanism making objective comparisons difficult. This trend may continue in 1992.

FIGURE 7
1991 CANADIAN POSTINGS minus WTI
TRANSPORTATION ADJUSTED TO EDMONTON
U.S. DOLLARS PER BARREL

PRODUCTION

Figures 8 and 9 summarize the total provincial production of conventional crude oil and the royalty share which is marketed by the APMC.

Royalty receipts of light and medium crude totalled 7.2 million cubic metres (45.3 million barrels), down 1.5 percent from 1990. Royalty receipts of heavy crude were 962 thousand cubic metres (6.1 million barrels), up five percent from 1990.

PIPELINE PROBLEMS

IPL's Lakehead system ruptured near Grand Rapids, Minnesota during March. As a result, the U.S. Department of Transport required a reduced pumping rate and ordered that the line be pressure tested. Accordingly, IPL initiated a hydrostatic test program in May of 1991. Reduced pipeline capacity and flow interruptions during four test periods plagued shippers for the balance of the year, creating a surplus of crude in western Canada and uncertain deliveries.

In the face of unprecedented high levels of pipeline capacity apportionment and uncertain delivery schedules, the APMC was able to fulfil all but a very small portion of its term delivered sales obligations and protect its positio.. as a reliable supplier.

NOMINATION PROCESS

Capacity constraints and nomination problems on IPL resulted in high levels of capacity apportionment for the entire year.

Producers and shippers attempted to protect their access to IPL capacity by over- estimating crude supply. By mid-year, the forecasting and nomination systems used to schedule feeder pipelines and IPL had broken down. Exaggerated supply forecasts inflated the capacity apportionment calculated by IPL and resulted in inequitable pipeline and market access.

FIGURE 8
ALBERTA CONVENTIONAL CRUDE OIL PRODUCTION
MILLION CUBIC METRES

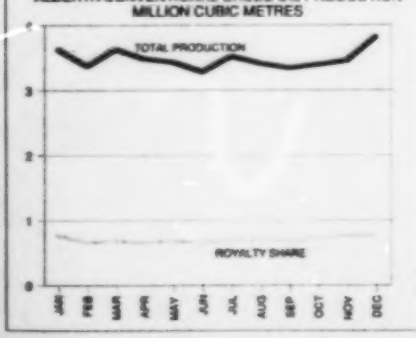
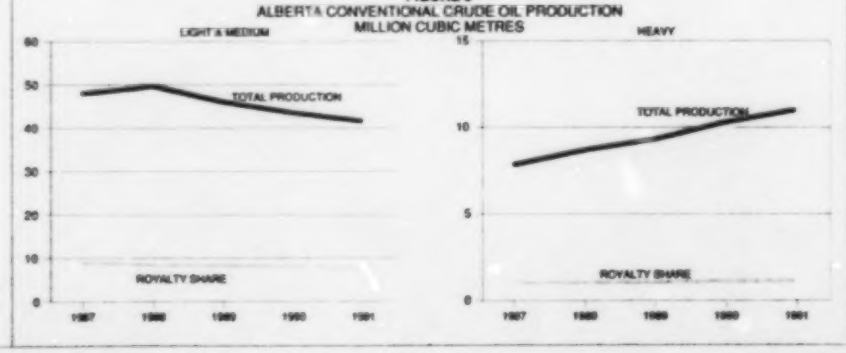


FIGURE 9
ALBERTA CONVENTIONAL CRUDE OIL PRODUCTION
MILLION CUBIC METRES



The APMC initiated the formation of, and participated directly in, an industry working group comprised of shippers, pipelines and producers to address the problem.

By year end, this group developed modified procedures designed to eliminate nomination problems and establish a more equitable system for controlling oil movements. These changes are slated for implementation in early 1992.

SARNIA - MONTREAL PIPELINE

Withdrawal of the last shipper from the Montreal Extension of IPL resulted in the line being de-activated and purged. The last volume of crude was removed from the line during July. Loss of the Montreal market contributed to a surplus of light sour and heavy crudes. Limited access to alternate markets caused Canadian crude prices to decouple from prices for competitive alternate supplies in U.S. Midwest markets. As a consequence, Canadian light/heavy price differentials reached unprecedented high levels.

During mid-year, the APMC negotiated with a Montreal refiner on behalf of itself and a number of heavy crude producers for a sale which would re-activate the Montreal Extension for shipments of Canadian heavy crude. Although relative prices appeared to support such an undertaking, the parties were unable to negotiate a mutually acceptable agreement.

Later in the year, IPL, with the support of four Ontario refiners, proposed the reversal of the Montreal Extension to bring offshore crude into Ontario. The APMC believes that premature reversal of the Montreal Extension will force Canadian crude into lower value markets, depress well head prices and ultimately reduce reserve replacement rates. The APMC has presented this view to industry and various government bodies including the National Energy Board.

NEW MARKETS

With on-going IPL pipeline capacity constraints during 1991, the APMC continued to pursue non-traditional markets. Weak demand for crude at Edmonton and low prices in the Puget Sound market caused the APMC to promote Alberta crude to Pacific Rim buyers in an effort to protect production against shut-in and stabilize markets. These efforts resulted in the sale of approximately 900,000 barrels of light royalty crude to the Chinese Petroleum Corporation in Taiwan during the fourth quarter of the year.

The APMC continues to pursue opportunities in the Pacific Rim and elsewhere to promote market diversification.

NATURAL GAS MARKETING ACT

Services Relating to Price Components

Under the authority of Part 1 of the Act, the APMC may provide the following services under a gas contract:

- the determination, confirmation, or verification of price components;
- the allocation of all or part of the amount of a price component to a gas contract;
- the redetermination or the calculation of adjustments of price components; and
- the implementation of other services that pertain to price components.

During 1991, the APMC provided price component services to three clients on a cost recovery basis.

Producer Support for Downstream Pricing

Part 2 of the Act provides for producer input to the resale price if producers and buyers have agreed to a netback pricing clause in their natural gas purchase contract. Regulations require the buyer to obtain support from producers representing a minimum of 51% by number and 60% by volume of supply.

Procedurally, a buyer presents a resale proposal to the producers for voting purposes and the results of the vote are provided to the APMC. A finding of producer support is issued if the legislated criteria are met. Shippers of netback gas may be subject to penalties imposed by the APMC if gas is shipped without a finding of producer support. During 1991, the APMC issued 65 decisions in respect of producer support.

During the year, Part 2 of the Act was amended to provide for the continuance of netback pricing agreements for a designated shipper who, in the opinion of the Lieutenant Governor in Council, is affiliated with or is otherwise influenced in favor of a major purchaser of gas acquired by that shipper. Once issued, a designation order continues in effect until November 1, 1994, unless producers vote in favor of terminating the application of the legislation in accordance with the regulations.

Information Collection

The APMC collects information relevant to the purchase and sale of marketable Alberta natural gas under Part 4 of the Act. The data collected include field purchase information provided primarily by first buyers, while figures relevant to consumption within Alberta are supplied by large volume end-users and designated distributors. Ex-Alberta sales information is provided by the owners of the natural gas when it leaves Alberta. Similarly, owners provide information pertinent to imports of natural gas into Alberta.

Information is collected on a confidential basis for use in developing government policies, verifying royalty payments and establishing the average market price (AMP) used to determine the royalty share of natural gas production. The statistics are also used to monitor development under the October 31, 1985 Agreement on Natural Gas Markets and Prices.

Responding to requests from industry, the APMC held two half-day workshops in November to review reporting procedures and problems.

TAKE-OR-PAY COSTS SHARING ACT

Under the terms of the October 1985 Agreement, the National Energy Board was requested to review the availability of transportation service on the TransCanada PipeLines Limited (TCPL) system, taking into account the equitable sharing of take-or-pay charges. In its May 1986 report, the National Energy Board recommended that take-or-pay costs be shared by Alberta non-system gas transported on the TCPL system, and that the arrangements be administered by the Government of Alberta.

In response, the Government of Alberta enacted the Take-or-pay Costs Sharing Act which became effective November 1, 1986. This Act provides for the sharing of take-or-pay financing costs of Consolidated Natural Gas Limited and TCPL by way of a monthly levy on users of the TCPL system whose shipping arrangements were entered into after October 31, 1985.

The levy on users of the system was set at ten cents per gigajoule for the period November 1, 1986, to October 31, 1989. Subsequently, the rates of levy have decreased to seven, five and three cents per gigajoule effective the months of November 1989, July 1991 and January 1992, respectively.

The APMC makes monthly determinations of levies to be applied to TCPL producers, Consolidated producers, shippers on the NOVA Corporation of Alberta system, shippers on other provincial carrier systems and to provincial carriers that own the gas. The APMC also makes monthly determinations on the quantities of natural gas exempted from the levies.

Revenues derived from the assessment of levies are deposited in the Take-or-pay Costs Sharing Fund for subsequent payment of take-or-pay financing costs. Levies assessed against parties, excluding TCPL and Consolidated producers, accounted for 47 percent of total levies during 1991.

NATURAL GAS PRICING AGREEMENT ACT

Under provisions of the Natural Gas Pricing Agreement Act, the APMC has authority to redetermine the Alberta cost of service for an original buyer for any month up to and including October 1986 in order to comply with decisions of the Alberta Public Utilities Board. During 1991, the APMC issued one such decision requiring amendments to several Alberta costs of service determinations. This APMC decision is the subject of an appeal to the Alberta Public Utilities Board at this time.

REGULATORY AFFAIRS

As the advocate for the Province of Alberta on regulatory issues, the APMC actively participates in and monitors regulatory proceedings throughout North America. The APMC's participation in these proceedings protects and enhances the value of the Province's petroleum resources and helps ensure that regulatory impediments do not frustrate market access by Alberta producers.

During 1991, the APMC was involved in various regulatory proceedings before the National Energy Board (NEB), Ontario Energy Board, and Manitoba Public Utilities Board in Canada, as well as the Federal Energy Regulatory Commission (FERC) and California Public Utilities Commission (CPUC) in the United States. Although these proceedings dealt with a myriad of issues, three themes predominated:

- pipeline facilities expansion and market growth;
- tolls and rate design; and
- pipeline service restructuring.

Developments in all three areas affect the competitiveness of Alberta's petroleum industry and the level of provincial royalty revenues.

FACILITIES EXPANSION AND MARKET GROWTH

A thriving petroleum industry depends, in large part, on the ability of producers to access new markets. The APMC was actively involved in several regulatory proceedings in both Canada and the United States in 1991, supporting the expansion of pipeline transportation systems where such projects could be demonstrated to have net economic benefits to the province.

In the spring of 1991, the NEB conducted a hearing into TransCanada Pipelines Limited (TCPL) proposed Blackhorse Extension, a 12-mile pipeline designed to interconnect with the proposed Empire State Pipeline Company, Inc. Project at Chippawa, Ontario. At the hearing, the APMC questioned the need for this expansion, its timing, cost and the adequacy of the underpinning supply. The APMC also questioned whether the proposed project was the most economic means of serving the upstate New York market. The NEB rejected TCPL's Blackhorse Extension application, stating that the proposed market could be served by a less expensive and environmentally superior expansion of the existing TCPL Niagara Line.

Simultaneously, the FERC approved the Empire State project, conditional upon the NEB's approval of the Blackhorse Extension. While the NEB subsequently announced its intention to revisit its earlier decision, this process was overturned by Canada's Federal Court based on irregularities regarding ex parte communications. The Empire sponsors have since filed a second application with the NEB for a review of the decision, which will be conducted during May 1992.

During the fall of 1991, TCPL's 1992/93 application for expanded facilities was heard by the NEB. The APMC questioned the need for the facilities, tariff matters, provision of facilities release packages to interested parties and financial assurances related to certain projects. In this context, the APMC indicated that "bumping", decontracting and TCPL's short-term renewal policy should be reviewed prior to the next facilities hearing. This would protect against potential overbuilding of the TCPL system and ensure the long-term utilization of the pipeline.

In the United States, the APMC supported a proposed expansion by Northern Border Pipeline Company to the FERC to reconfigure existing facilities and construct new lines which would transport up to 750 million cubic feet per day of additional capacity to delivery points in the United States Midwest. This expansion would increase the available market for Alberta gas and contribute to the competitiveness of the deregulated market. The FERC denied Northern Border's application as filed on the grounds that the pipeline had failed to demonstrate that markets exist for

the full incremental capacity. Northern Border subsequently amended its application to provide facilities for an additional 385 million cubic feet per day, with the costs to be rolled into the existing rate base. The amended application will be ruled on early in 1992.

In 1991, the FERC also made preliminary determinations approving expansions by Altamont Gas Transportation Company, El Paso Natural Gas Company, Northwest Pipeline Corporation, Pacific Gas Transmission Company and Transwestern Pipeline Company. The APMC closely monitored these proceedings as each directly or indirectly affects the ability of Alberta producers to penetrate new and existing markets.

TOLL DESIGN AND GENERAL RATE HEARINGS

Transportation toll and rate design issues continued to be prominent in 1991. The APMC was involved in several proceedings to ensure that Alberta producers share in the benefits of pipeline expansions and are not unduly discriminated against through pipeline toll design.

One of the more important regulatory issues of the year was addressed in Interprovincial Pipe Line Inc.'s Class 3 hearing. In that hearing, the NEB examined the appropriate tolling treatment to be applied in the event that a proposal to reverse the Montreal Extension between Sarnia and Montreal comes to fruition. The reversed pipeline would be used by Ontario refiners to import offshore crude oil.

While the APMC did not oppose the project, the APMC witnesses strongly advocated that the tolling method adopted be cost-based and reflect the principle of user-pay. The APMC argued that tolls which failed to take into account the federal government's deficiency payments for the line would result in a subsidy being applied to the cost for transportation services on the reversed line. This would provide a competitive advantage to one set of participants in the market at the expense of western Canadian producers. A decision regarding the appropriate toll methodology for the line is expected in 1992.

Debate on the issue of rolled-in versus incremental costing for new natural gas pipeline facilities also continued during 1991. In the United States, the FERC ruled that Great Lakes Gas Transmission Company (GLGT) may not use the FERC's traditional rolled-in rate making methodology but instead must establish separate incremental rates to recover the costs of each expansion. The APMC actively participated in this hearing, advocating rolled-in tolls for expansion facilities. Several parties to the proceeding, including the APMC, filed petitions for re-hearing on the basis that incremental rates are unduly discriminatory and confer inappropriate rights on existing shippers. Such tolls effectively act as a barrier to Canadian gas competing in the United States. The APMC will be active in the GLGT rehearing and general rates case in 1992.

The FERC also approved a move from modified fixed variable (MFV) toll design to straight fixed variable (SFV) in the GLGT case. The APMC supported this initiative because tolls based on the SFV methodology more accurately reflect costs and prevent cross subsidization. This approach also is consistent with the FERC's recently proposed rulemaking, the so-called "Mega-NOPR". The Mega-NOPR would mandate the unbundling of pipeline sales and transportation services, affording all users access to pipeline facilities and services on a comparable basis to that enjoyed by the pipeline company. It would also implement the SFV tolling methodology for most gas pipelines.

Since increases in pipeline transportation costs directly affect the netback received by Alberta producers and, correspondingly, the Alberta government's royalty share, the APMC actively participates in pipeline rate proceedings in Canada and the United States. In addition, as the marketer of Alberta royalty crude oil, the APMC is directly affected as a shipper by proposed rate increases on crude oil pipelines.

At the end of 1990, TCPL submitted its annual application to the NEB for new tolls effective January 1, 1991. The NEB approved new tolls effective July 1, 1991 which were, on average, 16 percent higher than those in effect during 1990. The APMC participated in the TCPL tolls hearing, advocating reduced costs and lower tolls.

In 1991, IPL and Trans Mountain Pipe Line Company Ltd. (TMPL) filed for transportation rate increases of five and 12 percent respectively. The APMC took an active role before the NEB in examining the appropriateness of these increases.

During 1991, the APMC was very active on industry-pipeline task forces established to resolve certain tolling and cost of service issues prior to a public hearing. The APMC has supported the task forces as the best means currently available to reduce hearing costs and regulatory delay. During 1991, the TCPL Tolls Task Force succeeded in reducing the number of issues to be considered at TCPL's 1992 Tolls Hearing scheduled for early 1992. Similarly, the TMPL Task Force was able to negotiate a consensus on certain key issues. The APMC will continue to participate in the task forces during 1992.

GAS TRANSPORTATION RESTRUCTURING

The North American natural gas transportation industry continued to move to a more market-based environment during 1991. This fundamental restructuring of natural gas transportation services is a significant undertaking and one in which the APMC has maintained a prominent role. The APMC has strongly supported the transition to a more market-based environment, advocating that transportation services should be a neutral factor in the pricing of natural gas. The APMC has advocated that policies regarding pipeline access should not work to systematically disadvantage producers.

The APMC actively participates in cases in various jurisdictions in which competitive developments directly affect Alberta's gas markets. In California, the CPUC fully implemented its non-core gas procurement (OIR) rules on August 1, 1991. The APMC participated in the implementation process to ensure that the Access Agreement negotiated between producers and California end-users was implemented as envisioned. On the heels of the OIR, the CPUC also pursued its agenda with regard to the provision of transportation services for aggregated small core volumes. In response, Pacific Gas and Electric Company (PG&E) converted a portion of its firm sales rights on Pacific Gas Transmission Company to firm transportation rights for use by core aggregators.

The APMC was very active during the year in the CPUC's capacity brokering proceeding which sought to adopt rules to govern the allocation of interstate and intrastate capacity rights of local distribution companies to their customers. Early in 1991, a settlement between primarily California interests proposed that interstate and intrastate capacity be bundled and that this capacity be preferentially allocated to California non-core end-users. This was unacceptable to Canadian interests.

The APMC, Canadian Petroleum Association and Independent Petroleum Association of Canada litigated the issue, arguing that existing contracts be recognized and the Access Agreement be maintained for its full term. The CPUC's final capacity brokering order released in November 1991 did neither. In response to the subsequent escalation in regulatory tensions, a series of negotiations between the Alberta and British Columbia governments and the CPUC commenced in December, convened under the Canada-United States Energy Consultative Mechanism. The APMC participated actively in these negotiations, which continued into 1992.

In response to regulatory developments in California, the NEB announced that it would hold a public hearing early in 1992 to review licences and transportation services to export gas to California. The APMC supported this review and will be an active participant at the hearing.

Also escalating market tensions in California during 1991 was the report filed at the CPUC by the Division of Ratepayers Advocates (DRA) in September regarding the reasonableness of PG&E's Canadian gas purchases. The DRA claimed that PG&E paid some $US 392 million too much for gas purchased from its Canadian affiliate, Alberta and Southern Gas Co. Ltd. during 1988, 1989 and 1990. The DRA also made recommendations for restructuring PG&E's Canadian gas supply arrangements. The case will be heard in 1992.

Other regulatory issues before the CPUC in which the APMC participated during 1991 included PG&E's expansion, the toll design for this expansion and utility cost allocation based on long run marginal costs.

Of great significance to all facets of the North American gas industry was the FERC's proposed rulemaking, the Mega-NOPR. The APMC filed comments on the proposed rules, agreeing with the concept of comparability, the elimination of capacity brokering and its replacement by a voluntary capacity release mechanism, the recognition of existing contractual arrangements and transition costs in any restructuring and the move to SFV rate design. The APMC will closely monitor the implementation of this rule as it directly affects Canadian producing interests, and will participate in compliance/restructuring proceedings during the coming year.

From Alberta's perspective, the most significant issues in these proceedings concern the allocation of capacity and the treatment of transition costs arising from restructuring of upstream supply and transportation obligations.

GENERAL MATTERS

During 1991, the APMC was active before the Manitoba Public Utilities Boad and the Ontario Energy Board. The APMC encouraged both Boards to approve the gas supply arrangements and gas costs brought before them arising from freely negotiated contracts. The APMC advocated that, in a substantially deregulated environment, such costs should be allowed to be passed through to end-users without undue regulatory interference.

During the fall of 1991, the NEB reviewed certain aspects of its Market Based Procedure, to lessen the regulatory burden associated with natural gas exports. While the APMC supported reduced regulatory oversight in general for export licences, it cautioned the NEB that the pace of deregulation in Canada should not overstep that in the United States because unfair competition could result.

During 1992, the APMC will continue to be vigilant on the regulatory front, to ensure that Alberta producers are able to compete on a fair basis in the evolving North American market.

ALBERTA LEGISLATURE

OFFICE OF THE AUDITOR GENERAL

AUDITOR'S REPORT

To the Members of the
Alberta Petroleum Marketing Commission

I have audited the balance sheet of the Alberta Petroleum Marketing Commission as at December 31, 1991 and the statement of operations for the Petroleum Marketing Fund and the statement of revenue and expenditure for the Operating Fund for the year then ended. These financial statements are the responsibility of the Commission's management. My responsibility is to express an opinion on these financial statements based on my audit.

I conducted my audit in accordance with generally accepted auditing standards. Those standards require that I plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In my opinion, these financial statements present fairly, in all material respects, the financial position of the Commission as at December 31, 1991 and the results of its operations and the changes in its financial position for the year then ended in accordance with the disclosed basis of accounting as described in Note 2 to the financial statements.

Donald D. Salmon

FCA
Auditor General

Edmonton, Alberta
March 13, 1992

BALANCE SHEET

At December 31,	1991	1990
ASSETS		
PETROLEUM MARKETING FUND		
Current		
Cash and short-term investments	$ 29,502,051	$ 20,851,894
Accounts receivable	130,924,810	193,227,513
Inventory held on behalf of the Province of Alberta	93,365,030	128,417,970
	253,791,891	342,497,377
OPERATING FUND		
Current		
Cash and short-term investments	3,719,399	5,029,812
Accounts receivable	414,171	261,195
	4,133,570	5,291,007
Capital assets, at cost *(Note 3)*	2,599,731	3,186,830
	6,733,301	8,477,837
	$ 260,525,192	$ 350,975,214
LIABILITIES		
PETROLEUM MARKETING FUND		
Current		
Accounts payable		
Purchases and transportation	$ 31,712,622	$ 41,449,987
Goods and services tax	12,584,861	-
Payable to the Province of Alberta		
Conventional oil - royalty share	176,066,032	258,824,871
Synthetic oil - equity share	33,428,376	42,222,519
	253,791,891	342,497,377
OPERATING FUND		
Current		
Accounts payable	258,691	205,575
Payable to the Province of Alberta	3,283,212	3,264,932
Deferred contributions *(Note 4)*	591,667	1,820,500
	4,133,570	5,291,007
Equity in capital assets	2,599,731	3,186,830
	6,733,301	8,477,837
	$ 260,525,192	$ 350,975,214

The accompanying notes are part of these financial statements.

STATEMENT OF OPERATIONS - PETROLEUM MARKETING FUND

Year ended December 31,	1991	1990
Revenue from crude oil sales	**$ 1,642,244,652**	$ 2,078,197,543
Expenditure		
Crude oil purchases *(Note 5)*	**225,741,744**	390,956,825
Transportation	**94,161,226**	89,422,755
	319,902,970	480,379,580
Excess of revenue over expenditure	**1,322,341,682**	1,597,817,963
Net revenue to the Province of Alberta		
Conventional oil - royalty share	**1,090,368,818**	1,338,672,268
Synthetic oil - equity share	**231,972,864**	259,145,695
	1,322,341,682	1,597,817,963
	$ -	$ -

STATEMENT OF REVENUE AND EXPENDITURE - OPERATING FUND

Year ended December 31,	1991	1990
Revenue		
Crude oil marketing fees	**$ 2,713,115**	$ 2,834,901
Interest	**1,713,887**	1,621,017
Natural gas price component service fees	**297,417**	322,248
Take-or-pay administration cost recoveries *(Note 6)*	**180,000**	-
	4,904,419	4,778,166
Expenditure		
Salaries and benefits	**5,296,431**	5,099,132
Office rental and maintenance	**1,044,056**	1,019,469
Regulatory hearings *(Note 7)*	**422,977**	829,685
Capital assets	**383,580**	157,214
Office supplies and services	**244,257**	231,703
Equipment rental and maintenance	**235,874**	177,694
Travel	**206,423**	193,555
Computer services	**149,495**	114,951
Consulting fees	**134,508**	77,184
	8,117,601	7,900,587
Excess of expenditure over revenue	**3,213,182**	3,122,421
Net contribution from the Province of Alberta *(Note 8)*	**3,213,182**	3,122,421
	$ -	$ -

NOTES TO THE FINANCIAL STATEMENTS

December 31, 1991

NOTE 1 AUTHORITY

The Alberta Petroleum Marketing Commission operates under the authority of the Petroleum Marketing Act, Chapter P-5, Revised Statutes of Alberta 1980, as amended, and the Natural Gas Marketing Act, Chapter N-2.8, Statutes of Alberta 1986, as amended.

NOTE 2 SIGNIFICANT ACCOUNTING POLICIES

General

These financial statements have been prepared in accordance with generally accepted accounting principles, except that vacation pay entitlements are not accrued and purchases of capital assets are charged to operating fund expenditure, net of disposal proceeds, in the year of acquisition. The balance sheet, however, states the cost of all capital assets presently owned with the offsetting credit to equity in capital assets. Capital assets are not amortized.

Inventory Held on Behalf of the Province of Alberta

Inventory held on behalf of the Province, representing Alberta's share of royalty and synthetic oil in feeder and trunk pipelines, is stated at net realizable value.

Foreign Currency Translation

Assets and liabilities denominated in foreign currency are translated into Canadian dollars at forward exchange contract rates or, where not covered by forward exchange contracts, at the rate of exchange in effect at the balance sheet date. Revenue and expenditures are translated at forward exchange contract rates or, where not covered by forward exchange contracts, at average monthly exchange rates.

Changes in Financial Position

A statement of changes in financial position is not provided as disclosure in these financial statements is considered adequate.

NOTE 3 CAPITAL ASSETS

During 1991, changes in capital assets were as follows:

	Opening Balance	Additions	Disposals	Closing Balance
Furniture and equipment	$ 2,344,363	$ 760,495	$ 1,396,105	$ 1,708,753
Leasehold improvements	842,467	130,743	82,232	890,978
	$ 3,186,830	$ 891,238	$ 1,478,337	$ 2,599,731

Computer equipment with an original cost of $1,294,170 was traded for new equipment valued at $498,332. These amounts are reflected in the above additions and disposals figures. The additions also include purchases of $392,906. Cash disposal proceeds amounted to $9,326.

NOTE 4 DEFERRED CONTRIBUTIONS

Contributions received from the Province of Alberta to cover operating costs for the period subsequent to the fiscal year-end have been deferred. Contributions by the Province are based on a yearly budget for the period April 1 to March 31.

NOTE 5 PETROLEUM MARKETING OPERATIONS

Agency Relationships and Marketing Services

Under the Petroleum Marketing Act, the Commission is designated agent of the Province of Alberta to accept delivery of, and market the Crown's royalty share of crude oil. Through an agreement dated August 4, 1977, the Commission is also designated agent of the Province to market its 16.74 percent equity share of production from the Syncrude Canada project. In addition, the Commission offers marketing services to Alberta producers.

Crude Oil Purchase/Sale Exchange Agreements

In order to assist in meeting its sales obligations, the Commission enters into crude oil exchange agreements. Sales and purchases under these agreements are included in revenue and crude oil purchases. In 1991, these purchases amounted to $124,949,929 (1990: $232,099,770).

NOTE 6 TAKE-OR-PAY ADMINISTRATION COST RECOVERIES

The Take-or-pay Costs Sharing Fund is administered by the Commission pursuant to the Take-or-pay Costs Sharing Act. Costs incurred in the administration of this Fund are included in the Statement of Revenue and Expenditure - Operating Fund. Commencing January 1, 1991, these costs are recovered by a charge against the Take-or-pay Costs Sharing Fund.

NOTE 7 REGULATORY HEARINGS

Regulatory hearing costs are comprised of the following:

	1991	1990
Outside counsel and consultants	$ 340,167	$ 671,513
Travel	59,594	110,909
Transcripts	23,216	47,263
	$ 422,977	$ 829,685

NOTE 8 NET CONTRIBUTION FROM THE PROVINCE OF ALBERTA

The Commission receives funding from the Province, based on its budget year of April 1 to March 31. For the 1991-92 budget year this will amount to $7,285,000 (1990-91: $8,017,000). Revenues from crude oil marketing fees, interest, natural gas price component service fees and take-or-pay administration cost recoveries are used to reduce the operating grant requirement and any surplus is subsequently returned to the Province. During the year this surplus amounted to $4,649,041 (1990: $4,569,040).

NOTE 9 COMMITMENTS

Effective December 1, 1981, the Commission signed a fifteen year lease for office accommodation at a minimum annual rental of $692,360 plus occupancy costs.

Effective August 30, 1991, the Commission signed a three year computer facility maintenance agreement at an annual cost of $132,000.

NOTE 10 APPROVAL OF FINANCIAL STATEMENTS

These financial statements were approved by the Commission.

ALBERTA LEGISLATURE

OFFICE OF THE AUDITOR GENERAL

AUDITOR'S REPORT

To the Members of the
Alberta Petroleum Marketing Commission

I have audited the balance sheet of the Take-or-pay Costs Sharing Fund as at December 31, 1991 and the statement of revenue and expenditure for the year then ended. These financial statements are the responsibility of the Commission's management. My responsibility is to express an opinion on these financial statements based on my audit.

I conducted my audit in accordance with generally accepted auditing standards. Those standards require that I plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In my opinion, these financial statements present fairly, in all material respects, the financial position of the Fund as at December 31, 1991 and the results of its operations and the changes in its financial position for the year then ended in accordance with generally accepted accounting principles.

Donald D. Salmon

FCA
Auditor General

Edmonton, Alberta
March 13, 1992

TAKE-OR-PAY COSTS SHARING FUND

BALANCE SHEET

At December 31,	1991	1990
ASSETS		
Current		
Cash and short-term investments	$ 3,147,851	$ 3,319,339
Accounts receivable	5,083,981	10,684,487
	$ 8,231,832	$ 14,003,826
LIABILITIES		
Current		
Accounts payable	$ 2,174,925	$ 4,080,112
Deferred revenue *(Note 3)*	6,056,907	9,923,714
	$ 8,231,832	$ 14,003,826

STATEMENT OF REVENUE AND EXPENDITURE

Year ended December 31,	1991	1990
Revenue		
Take-or-pay levies	$ 76,623,059	$ 139,459,972
Interest	303,023	328,212
	76,926,082	139,788,184
Expenditure		
Take-or-pay costs	76,746,082	139,788,184
Administration costs *(Note 4)*	180,000	-
	76,926,082	139,788,184
Excess of revenue over expenditure	$ -	$ -

The accompanying notes are part of these financial statements.

NOTES TO THE FINANCIAL STATEMENTS

December 31, 1991

NOTE 1 AUTHORITY

The Take-or-pay Costs Sharing Fund was established by the Take-or-pay Costs Sharing Act, Chapter T-0.1, Statutes of Alberta 1986, as amended.

NOTE 2 SIGNIFICANT ACCOUNTING POLICIES

Changes in Financial Position

A statement of changes in financial position is not provided as disclosure in these financial statements is considered adequate.

NOTE 3 DEFERRED REVENUE

Deferred revenue represents the portion of current year revenue which will be used to pay future take-or-pay costs.

NOTE 4 ADMINISTRATION COSTS

In accordance with the Take-or-pay Costs Sharing Act, the Fund is administered by the Alberta Petroleum Marketing Commission. Costs of administration are reflected in the Statement of Revenue and Expenditure - Operating Fund. Commencing January 1, 1991, these costs are recovered by a charge against the Take-or-pay Costs Sharing Fund.

NOTE 5 APPROVAL OF FINANCIAL STATEMENTS

These financial statements were approved by the Commission.

DIRECTORY

COMMISSION *

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Acting Chairman

DAVID L. WILLIS
Vice Chairman

GENERAL COUNSEL AND SECRETARY

PATRICIA A. McCUNN-MILLER

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Comptroller

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Manager, Financial Accounting - Petroleum

BRIAN R. ZAPFE
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WILLIAM A. ZANEWICK
Manager, Natural Gas Operations

* Dale A. Lucas resigned from the Commission on December 31, 1991, after serving as Chairman since 1984.

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